Pacific Gas and Electric Company

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December 1, 2004

REGULAR MAIL

California Energy Commission
Attn: Docket Unit
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Re: PG&E's Comments to the Rule 21 Working Group Report filed in Docket Number "04-DIST-GEN-1"

Dear Docket Unit:

Enclosed for filing are the original and eleven (11) copies of Pacific Gas and Electric Company's "Comments to the Rule 21 Working Group Report" and associated attachment submitted to docket number 04-DIST-GEN-1.

These documents were also electronically filed with the California Energy Commission Docket Unit on November 30, 2004.

Sincerely,

Stacy W. Walter

SWW/pak

Enclosures

November 30, 2004

Pacific Gas and Electric Company's Comments On The Rule 21 Working Group Report Regarding Recommended Changes To Interconnection Rules issued on November 10, 2004 (Docket 04-DIST-GEN-1)

California Energy Commission
Re: Docket No. 04-DIST-GEN-1 and
Docket No. 04-IEP-01
Docket Unit, MS-4
1516 Ninth St.
Sacramento, CA 95814-5504
E-mail: docket@energy.state.ca.us

Pacific Gas and Electric Company (PG&E) respectfully submits the following Comments on the *Rule 21 Working Group Recommended Changes To Interconnection Rules Working Group Report* (Report) issued on November 10, 2004, for the consideration of the California Energy Commission. The focus of these comments is not to reargue issues that are already laid out in the Report. Instead, the focus of these comments is to make the final version of the Report clearer and more accurate. PG&E has summarized its comments here and attached a copy of the Report incorporating these items in a redline format.

__Metering Issues__

In several places, the Report claims that the utilities believe that Net Generation Output Metering (NGOM) should be required "In All Circumstances." That is not PG&E's position. Most DG installations have not required NGOM, particularly the thousands of net metered projects that have been interconnected in the last few years. Moreover, some areas where PG&E thinks NGOM should be required do not appear to be controversial. PG&E's position is that NGOM should be required for certain new non-net energy metering interconnections. These include:

- Generating facilities receiving standby charge exemptions;
- Cogeneration customers as needed for tariff administration;
- Generating facilities participating in the California Public Utilities Commission (CPUC) Self Generation Incentive Program (SGIP); and
- Certain larger generators requiring telemetry.

NGOM is needed for generating facilities with standby charge exemptions for reasons explained well in the Report, which do not appear to be disputed.[1]

[1] Section 353.15 of the Public Utilities Code, which contains specifications for generating units that qualify for standby charge exemptions, requires an ongoing evaluation of generator efficiencies, emissions, and reliability. To perform this evaluation, the Code requires the customer to annually

Cogeneration customers need NGOM in order to know whether the customer qualifies for various benefits. Certain tariffs require the generator to operate as a "cogenerator" in compliance with Public Utilities Code section 218.5 or other relevant law. Monthly kWh data is gathered in order to calculate monthly bills and calendar-year operating efficiency. Data is used to determine cogeneration is meeting the operating efficiency requirements per PUC Section 218.5.

Generators receiving SGIP funds must have NGOM due to program requirements. Fossil fuel–fired generators receiving such funds are required to have supplementary metering to record waste heat utilization, and fossil and renewable fuel generators are to have metering to measure renewable fuel consumption. The data from these meters is used for program evaluation, measurement and verification (EM&V). Unless required for some other reasons, the incremental cost of such metering not paid for by the generator, but is instead paid out of the SGIP EM&V budget.

Telemetry is already required for certain larger generators so the system operator can monitor generator operating status. In particular, Rule 21, Section F.5 (Telemetering) states:

> If the nameplate rating of the Generating Facility is 1 MW or greater, Telemetering equipment at the Net Generator Metering location may be required at the Producer's expense. If the Generating Facility is Interconnected to a portion of PG&E's Distribution System operating at a voltage below 10 kV, then Telemetering equipment may be required on Generating Facilities 250 kW or greater.

While not mandatory, certain other customers would also benefit from NGOM since it is more accurate than estimating generator output and could reduce billing issues for these customers. However, PG&E has not required NGOM for administration of non-bypassable charge exemptions. Appendix A of the Report includes more detail regarding PG&E's position on when NGOM is required and when it would be beneficial.

Finally, PG&E is concerned that there continues to be confusion regarding whether or not NGOM is required for customers taking service under a net energy metering (NEM) tariff for eligible solar, wind, biogas or fuel cell customers. Under such programs, the customer receives a retail credit for the generation value of the energy delivered to the grid. PG&E currently sees no need for NGOM metering for any of these NEM customers. Until such time as the NEM programs change or NGOM becomes part of the solution to combining NEM and non-NEM technologies, PG&E sees no reason to employ NGOM in NEM facilities.

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provide such information to the CPUC, recorded on a monthly basis. This information cannot be gathered without NGOM equipment.

Interconnection Fees

PG&E agrees that there is no need to change the basic application fee structure for interconnection applications. However, PG&E recommends that a change be made in the cost structure for pre-parallel inspections for non-net energy metered interconnections. PG&E inspectors are frequently required to make multiple inspection site visits when a customer is not ready on the date of the first inspection.

So far in 2004 PG&E has averaged approximately $10,000 in pre-parallel inspection costs per non-net metered DG interconnection. Typically multiple trips are required because the customer is not ready to interconnect on the first visit. PG&E's believes it would be more equitable for the party responsible for the problem that creates the need for a second or third trip to cover the cost of any pre-parallel inspections after the first attempt. If the DG customer is the responsible party, the customer should pay for all inspections after the first one. However, PG&E agrees that if the subsequent visit is due to utility error, there should be no additional charge for the customer.

PG&E appreciates the opportunity to provide these comments and respectfully requests that the CEC adopt the changes included in the attached copy of the Report.

Sincerely,

SZ Walter

Stacy Walter

Attached: Redline of Working Group Report With PG&E Comments.

DISCLAIMER

This report represents a consensus opinion of the Rule 21 Working Group on certain Phase I issues. In other instances where consensus has not been reached, the different positions of individual Rule 21 Working Group stakeholders are identified. This paper generally reflects the experience of many stakeholders who work within the distributed generation community on a regular basis.

Stakeholders wishing to further elaborate on any positions are expected to do so in written comments due November 30, 2004 or at the Integrated Energy Policy Report Committee Hearing scheduled for December 10.

DEDICATION

This report is dedicated to the memory of Joseph J. Iannucci, a true pioneer and visionary in the advancement of distributed generation.

ACKNOWLEDGEMENTS

Energy Commission staff appreciates the extensive contributions made to the development of this report by the California Rule 21 Working Group participants. Special recognition is given to Nora Sheriff, Robin Luke, Mike Iammarino, Dan Tunnicliff, Gerry Torribio, Chuck Whitaker, and Jerry Jackson for their specific contributions in leading the development of the draft issue papers which form the foundation of this report. Additionally, other participating members of the Rule 21 Working Group are recognized for the continued support of improving California's interconnection rules:

Name	Affiliation	Name	Affiliation
Pat Aldridge	SCE	Art McAuley	PG&E
Manuel Alvarez	SCE	David Michel	CEC
Chuck Arthur	Arthur Engineering	Randy Minnier	MPE Consulting
Tom Blair	City of San Diego	William Monson	MRW & Associates
Werner Blumer	CPUC Energy	Steven Ng	PG&E
Bill Brooks	Endecon Energy	Ken Parks	SDG&E
David Brown	SMUD	Robert Patrick	Valley Air Solutions
Petrina Burnham	SDG&E	Edan Prabhu	Reflective Energies
Bill Cook	SDG&E	Dave Redding	Riverside Public Utilities
George Couts	SCE	Jim Ross	CAC/EPUC
Kevin Duggan	Capstone Turbine	Laura Rudison	SCE
Michael Edds	DG Energy Solutions	Dylan Savidge	PG&E
Jeff Goh	PG&E	Joe Simpson	Joe Simpson
Dana Griffith	NCPA	Richard Smith	SDG&E
Ed Grebel	SCE	Chuck Solt	Lindh & Associates
Hann Huang	ANL	Chuck Sorter	BluePoint Energy
Michael Hyams	San Francisco PUC	Mohammad Vaziri	PG&E
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Scott Lacy	SCE		
Mike Mazur	3 Phases Energy	Eric Wong	Cummins West, Inc.

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INTRODUCTION

On April 21, 2004, the California Energy Commission (Energy Commission) began an investigation to explore a variety of issues associated with the deployment of distributed generation (DG). The effort supports a complementary proceeding being undertaken by the California Public Utilities Commission (CPUC) through its proceeding (R.04-03-017). As part of the collaborative efforts of the two agencies, the Energy Commission agreed to develop recommendations in this proceeding and bring them forth for final consideration in the CPUC's proceeding.

As the August 17, 2004 Energy Commission scoping order indicated, the Rule 21 Working Group was tasked with developing an initial set of recommendations to be evaluated by the Energy Commission's Integrated Energy Policy Report Committee. This report represents the Working Group's response to that request.

As general background, the Rule 21 Working Group includes representatives from all aspects of the DG community, with utility personnel, DG manufacturers, project developers, DG customers, and regulators. Approximately 35 members actively participate in regular meetings, held every 4-6 weeks. Another 200 members track developments via an e-mail distribution list. Updated materials related to the Working Group, including meeting minutes, Rule 21 equipment certification information, as well as technical documents are available on the Energy Commission website at www.energy.ca.gov/distgen/interconnection/ interconnection.html.

The Energy Commission oversees the Working Group. Contract technical support is funded by its Public Interest Energy Research program. To date, approximately $1.2 million of public funding has been used to support the Rule 21 effort.

The initial focus was to craft a model Rule for the interconnection of distributed generation facilities installed and operated by utility customers. This was generally accomplished during calendar year 2000. The group now meets for the purpose of: 1) addressing more complex issues that have arisen; and 2) improving the interconnection process. Issues are debated and addressed in varying degrees. Resolution of such issues has often been reached. In some instances, however, additional policy direction from policymakers is required.

INTERCONNECTION ISSUES AND SUMMARY OF RECOMMENDATIONS

This report focuses on five key interconnection issue areas: Metering Issues; Dispute Resolution Process; Interconnection Fees/Costs; Net Metering for Systems with "Combined" Technologies; and Interconnection Rules for Network Systems. The issues were debated extensively over the course of four Rule 21 Working Group meetings held in September and October, with feedback provided to the larger group via e-mail and phone conversations.

Based on those deliberations, the Working Group offers the series of recommendations shown in Table 1. The remainder of the document provides the details surrounding the recommendations.

TABLE 1
PRINCIPAL RECOMMENDATIONS REGARDING INTERCONNECTION RULES

Issue	Conclusions and Recommendation
Metering Issues	Limited agreement was reached by the Working Group regarding certain situations when net generation output metering is required. In situations where agreement was not reached, policy guidance is needed with respect to: 1) the utility's desire to require net generation output meters for certain DG projects interconnecting to the utility system versus the DG community's desire to use estimated consumption or to use other meters; 2) regulatory responsibility for third-party meter ownership and meter quality/data standards if third-party meters are allowed; and 3) cost responsibility for the meters. It should be noted that these issues have been debated in excess of two years in the Working Group forum. A detailed discussion of the various positions is contained in Section I of this report.
Dispute Resolution Process	The Working Group seeks a policy decision about whether there is a need to change the current dispute resolution process. Some parties believe no changes are needed at this time. Others recommend modifications that will incorporate mediation from the CPUC's Energy Division, tighter timelines for review and resolution, and a clearer identification of technical and process decision-makers. No modifications are proposed to be incorporated based upon review of the Massachusetts' dispute resolution process.
Initial/Supplemental Interconnection Review Fees	The majority of the Working Group recommends that there is no change to the fee structure at this time. PG&E has proposed a simple change in which a generator would be charged for the cost of subsequent pre-parallel inspections after the first. Some parties propose that aAn ongoing utility tracking and reporting system ~~should~~ be established to provide detailed data on interconnection costs and assist regulators in making informed decisions regarding the future allocation of interconnection review costs. However, no specific proposal has been presented for discussion.
Net Metering for Systems with "Combined" Technologies (Multiple Tariffs)	For the purpose of interconnecting combinations of net energy metering (NEM) and non-NEM generating facilities of multiple tariffs to the grid, policy guidance is required on the appropriate treatment of export, tariffs, and cost responsibility, applicable to such a facility. No consensus has been reached by the Working Group at this time. Issues remain in the areas of tariff administration, equitable allocation of interconnection cost responsibility and tariff charges, which may be beyond the scope

TABLE 1 PRINCIPAL RECOMMENDATIONS REGARDING INTERCONNECTION RULES	
Issue	Conclusions and Recommendation
	of this proceeding. Policy issues remain regarding the fundamental intent of the NEM program as established by the state legislature.
Interconnection Rules for Network Systems	The Committee should direct the Rule 21 Working Group to develop network interconnection rules that can be incorporated into the current framework of Rule 21. The Working Group estimates that a preliminary Rule 21 requirement for network systems could be developed during the next 12 months. Once a new IEEE standard on the issue of network systems is complete, which could take 3-5 years, Rule 21 will be revised consistent with the adopted IEEE standard.

METERING ISSUES

Should the utility require a customer to utilize a utility-supplied meter on its generation units?

Should each new customer be financially responsible for the installation, operation, and maintenance of utility-supplied billing-grade metering on all new customer generation units?

The Committee's August 17 Scoping Memo requested input on whether customers should bear financial responsibility for a meter and whether the utility should require customers to use a utility-supplied billing-grade meter on the customers' generation units. In this paper, the focus of the metering discussion is on Net Generation Output Metering (NGOM), which is a meter specifically designed to record the electrical production of a DG facility.[1] Other terms such as *Net Metering, Net Energy Metering,* and *Net Generation Metering* have different meanings to different audiences. Therefore, NGOM will be used throughout to specifically refer to metering specifically designed to record the electrical production of a DG facility.

This issue is by far the most contentious in this proceeding. The Rule 21 Working Group began the debate in the summer of 2002 with the intent of resolving them under the current rule structure. However, the debate continues today and is clarified for the Committee's consideration. Table 2 contrasts the basic positions of the utilities and the position of the other parties in the proceeding.

TABLE 2
BASIC POSITIONS ON NET GENERATION OUTPUT METERS

Utility Positions	Positions of Other Parties
NGOM should be required for: 1) ~~all~~certain new non-NEM interconnections, and 2) all facilities with multiple generators. Meters must be revenue quality, either utility-owned or third-party-owned meeting metering standards contained in Rule 22.	NGOM should be required when the customer receives publicly-funded incentives or tariff exemptions. NGOM is unwarranted when less intrusive methods or cost effective means of providing data are available. The need for billing-grade or utility-owned meters is not always necessary.

[1] NGOM is defined in Rule 21 Section H to be the following:

Metering of the net electrical power of energy output in kW or energy in kWh, respectively, from a given Generating Facility. This may also be the measurement of the difference between the total electrical energy produced by a Generator and the electrical energy consumed by the auxiliary equipment necessary to operate the Generator. For a Generator with no Host Load and/or Public Utilities Code Section 218 Load (Section 218 Load), Metering that is located at the Point of Common Coupling. For a Generator with Host Load and/or Section 218 Load, Metering that is located at the Generator but after the point of auxiliary load(s) and prior to serving Host Load and/or Section 218 Load.

Recognizing the diversity of opinions shown in the table, the following discussion expands on these positions and is intended to be a starting point for the Committee's policy development on the NGOM issue. In doing so, we respectfully ask the Committee to consider the following questions:

- When ~~s~~Should NGOM be required? No party claims it is required for all DG. ~~in all circumstances, or should it only be required in some circumstances?~~
- When NGOM is required,
  1) Should the meter be of revenue quality?
  2) Can non-utility parties own the meter?
  3) Which party should pay for the meter?
- How can the policy considerations included in this proceeding be appropriately synergized with the results of the cost-benefit analysis being conducted by the CPUC in R.04-03-017?

Metering, Monitoring and Telemetry conditions are currently addressed in Section F of Rule 21. As the Section indicates, the utilities can require the installation of NGOM equipment and specify the type. This requirement, however, does have its limitations.

As the rule indicates, NGOM equipment can be required when "less intrusive and/or more cost effective options for providing the necessary Generating Facility output data are not available." The utilities must consider of variety of factors when determining the need for NGOM equipment, including the following:

- Data requirements in proportion to need for information;
- Producer's election to install equipment that adequately addresses the utilities' operational requirements;
- Accuracy and type of required Metering consistent with purposes of collecting data;
- Cost of Metering relative to the need for and accuracy of the data;
- The Generating Facility's size relative to the cost of the Metering/monitoring;
- Other means of obtaining the data (e.g., Generating Facility logs, proxy data, etc.); and
- Requirements under any Interconnection Agreement with the Producer.[2]

[2] Source: Rule 21, Section F.3.

When Should NGOM Be Required ~~in All Circumstances~~?

Circumstances Requiring NGOM Equipment

To comply with the provisions of several statewide DG incentive programs, NGOM is explicitly required in a number of instances. As explained below, the requirements for NGOM equipment are not necessarily driven by the technical aspects of the interconnection but rather the tariff-related provisions of the DG project.

Generating Facilities Receiving Standby Charge Exemptions

Section 353.15 of the Public Utilities Code, which contains specifications for generating units that qualify for standby charge exemptions, requires an ongoing evaluation of generator efficiencies, emissions, and reliability.[3] To perform this evaluation, the Code requires the customer to annually provide such information to the CPUC, recorded on a monthly basis. This information cannot be gathered without NGOM equipment.

Generating Facilities Participating in the CPUC's Self-Generation Incentive Program (SGIP)

All SGIP participating generating systems are required by the SGIP Handbook to have electric NGOM.[4] The following language from the SGIP Handbook describes the required metering:

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3 These requirements apply to generators above 10 kilowatts. Specific data required by the Code is paraphrased here and includes: 1) Heat rate for the resource; 2) kilowatt-hours produced during peak and off-peak periods, as determined by the ISO; and 3) emissions data for the resource, as required by the Air Resources Board, appropriate air quality management district, or air pollution control district.

4 The SGIP Handbook is developed through a working group process established by CPUC Decision 01-03-073 and provides implementation details for the program. The decision established the parameters of the required monitoring of SGIP participating customer generators, stating, "*measurement and verification protocols established by the administrators include some sampling of actual energy production by the funded self-generation unit over a statistically relevant period.*" D.01-03-073, at 19. This decision then clarifies that program administrators, while required to monitor the extent of SGIP generator operation during peak hours, must use "*independent evaluation consultants or contractors to develop a process for monitoring and collecting this data from program participants.*" D.01-03-073, at 32. These independent consultants are also supposed to install the hardware and software necessary, "***not*** *utility personnel.*" *Id.*, at 20 (emphasis added). Moreover, it is those consultants or contractors, not the program administrators, who are to "*present recommendations on incentive program designs that could improve on-peak load reduction from self generation.*" *Id.* The CPUC directed, "*If the self*

Every system installed under the program shall be equipped with a dedicated, recording, time-of-use or interval meter to measure and record electrical generation output (i.e. Net Generation Output Meter). Many installations will require this type of electrical metering as a condition of interconnection with the utility grid. In the case of investor owned electric utilities, this means compliance with their filed CPUC Rule 21, Generating Facility Interconnections. (Handbook date 1/17/04, Revision 4, Section 5.2.1)

Additional metering is required for fossil fuel-fired generation participating in the SGIP. Fossil fuel –fired generators are to have supplementary metering to record waste heat utilization, and fossil and renewable fuel generators are to have metering to measure renewable fuel consumption. Based on the current SGIP Reservation Request Form, the use of the data from these meters is limited to program evaluation, measurement and verification (EM&V). The cost of such metering is not paid for by the generator, but is instead paid out of the EM&V budget.

Special Gas Rates

All cogeneration customers who take service under the gas rate that applies to gas fired electric generation (in PG&E's case, schedule G-EG) must meet operating efficiency requirements established under Section 218.5 of the Public Utilities Code. This operating efficiency standard requires knowledge of each generator's net monthly kWh production. Additionally, utilities need monthly kWh production where the customer does not have a dedicated utility gas meter that measures only the gas input to the generator. Monthly kWh production is used to validate the amount of gas that qualifies for the cogeneration rate. This latter instance requires timely retrieval of the data by the utilities in order for timely and accurate bills to be presented to customers.~~Some cogeneration customers receive a special gas rate pursuant to Section 218.5 of the Public Utilities Code. NGOM is needed for the correct application of the cogeneration gas rate.~~

Certain "Net Energy Metering" Projects

generation unit ***does not already have built-in logging capability for this purpose [obtaining operational data for evaluation], then the unit could be outfitted with a low-cost single-channel data logger and sensor (such as a relay switch) which would at least enable the utility to determine when the unit is operating and producing electrical output.*** *Program administrators should develop and disseminate the specific requirements for system installations and monitoring capabilities required program evaluation" Id.*, at 33 (emphasis added).

Sections 2827, 2827.8, 2827.9 and 2827.10 of the Public Utilities Code outlines basic metering provisions of net energy metering (NEM) projects. These projects do not require NGOM metering but they do have different metering requirements depending on the type and size of the generator ~~While most projects generally do not require NGOM, NEM wind projects greater than 50 kilowatts, as well as NEM projects under the CPUC's pilot biogas and pilot fuel cell programs, may require NGOM for program administration and to properly credit energy generated by the DG facility.~~[5]

For most solar NEM customers, net energy is measured using a single meter which registers the flow of electricity in two directions. The utility has the option to install a dual meters to provide the information necessary to accurately bill or credit the customer.[6] The expense for the dual meter depends on the type of project. In most cases, the utility is responsible for the cost of the dual meter, with the exception of NEM projects under the CPUC's pilot biogas and fuel cell programs. Metering required for these projects are specifically required to be revenue quality.

Combined Technologies

When a NEM-eligible customer has a photovoltaic system in addition to a wind energy system with a capacity above 50 kW, or perhaps a biogas and/or fuel cell system combined with a photovoltaic system, the need for revenue quality metering at the generating facility is imperative in order to calculate credits and charges for the different kinds of rate treatment utilized under this scenario. In one such example, whereas a combined photovoltaic/wind energy system below 50 kW receives credits at the full retail price, all other types of NEM systems (i.e., Wind above 50 kW, Biogas and Fuel cell) receive credits based on the generation component of the utility's retail rate only.

Circumstances That May Not Require NGOM Equipment

Existing utility tariffs have provisions for measuring and estimating consumption as the basis for billing non-bypassable charges (Departing Load, Tail Competition Transition, Nuclear Decommissioning, Public Purpose Program) when NGOM is not available. The key to this provision is if reliable metered consumption information is not available to the utility.[7]

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5 For further information, see Sections 2827.8, 2728.9, and 2827.10 of the Public Utilities Code. Also, see the utilities' individual "net energy metering" tariff provisions regarding metering.

6 The utility can refuse the interconnection if the customer does not consent to the installation of the dual meter.

7 This information is referenced in SCE Preliminary Statement W, SCE Schedule DL-NBC, PG&E Preliminary Statement BB, SDG&E Electric Rule 23,

If reliable metered consumption information is not available to the utility, an estimate may be used. Utility tariffs then uniformly state that customer may choose one of two (or three, in SDG&E's territory) proposed methods for estimation of the customer's consumption. For example, SCE's tariffs state that the Departing Load customer's monthly consumption estimate will be based on the customer's historical load at the time it discontinues or reduces retail service with SCE, using either: a) the customer's demand and energy usage over the 12 month period prior to the customer's submission of notice; or b) the customer's average 12 month demand and energy usage, with such average to be as measured over the prior 36 months of usage.

Utility Positions

The utilities assert that Rule 21 gives them the discretion to require NGOM on generating units when they believe that such metering is necessary for accurate billing or regional monitoring. ~~Presently, all utilities require NGOM for this purpose.~~ SDG&E's position has been to consistently require ~~since the rule was first adopted and requires~~ NGOM on all customer generation since the rule was adopted. SCE ~~and PG&E~~ holds the same position currently although they~~each~~ had previously allowed third-party metering and data collection arrangements for DG interconnections. PG&E has prepared Appendix A to illustrate that NGOM, while not required for all generator installations, is required for four generator applications: generators qualifying for certain tariff exemptions by operating as a "cogenerator" in compliance with California PU Code Section 218.5, generators receiving a rebate under PG&E's self-generation incentive program, generators who are required to have a NGOM under Rule 21, Section F.5 (Telemetering) and customers eligible for a standby waiver. Again, PG&E does not require NGOM for all DG installations and, where it is required, unless telemetry is required, the metering requirement is merely a totalizing kilowatt-hour meter that is non-time-of-use. PG&E asserts that, in most instances, the requirement is similar to that of residential meter.[8]

In essence, each utility concurs that the alternative reporting requirements contained in Section F.3 are inadequate to let it effectively and accurately administer its tariff provisions as well as to determine its resource needs to provide safe reliable service to its customers.[9] PG&E argues that the use of non-metering alternatives produces information gaps and data integration issues, often requiring the need to input data manually. PG&E points to customers' inability to provide the necessary data in a timely manner, or their inability to provide data that is accurate or in a format that is readily useful for billing purposes. In some instances customers have simply refused to provide the data, indicating that the data is proprietary. ~~customer reluctance to provide data the customer believes is proprietary data but the utility views as critical to its billing and/or operational functions.~~

[8] Attached Appendix A provides additional detail regarding PG&E's position on NGOM.

[9] SDG&E's shares its experience with a customer who is responsible for providing the required data. Since the beginning of the DG's operation in 2000, through current day, the data supplied to SDG&E: 1) is provided to SDG&E on a computer spreadsheet and is not verifiable by any other source; 2) is not in a compatible billing format so SDG&E must manually manipulate and input the data to its billing system; and 3) typically arrives later than requested. SDG&E concluded early on that alternative methods of obtaining meter data would result in difficulties and additional cost to SDG&E's ratepayers.

SCE cites the difficulty of re-integrating data due to the lack of a common format for information provided by customers. Moreover, SCE states that some customers are averse to having tariffs administered by estimated usage and have complained about the utility estimates used for billing purposes. SCE further contends that, due to the uncertainties in accuracy and the incompatibility of data formats, installation of a billing-grade meter is required to measure the output of the customer's generator for acquiring data needed for the operation and planning of their electric systems.

Regarding the desire to use estimation as a regular billing feature in lieu of a meter, SCE puts forth the opinion that estimation should be used sparingly and not in an ongoing manner and that eventually a meter read needs to be obtained. As SCE contends, customers often reject the estimated bills, requiring a different method to obtain usage and a need to often re-bill the account. This is an expensive, manual process.

~~Rule 21 also states that the utilities can specify the type and installation of a meter to bill standby and non-by-passable charges.~~ Rule 21 does indicate that less intrusive and/or more cost effective options for providing usage can be used but the rule is silent on using estimation for an indefinite period. To do so, according to SCE, would be a violation of Section 770(d) of the Public Utilities Code. While tariffs and rules can be changed by Advice Letter, the Public Utilities Code can only be changed by Legislation. SCE concludes it would be inconsistent with PU Code Section 770(d) to allow continuous estimation of usage for billing purposes.[10]

The Working Group notes that the CPUC is scheduled to submit a report to the California Legislature by January 1, 2005 on the costs and benefits of NEM per PUC 2827(n). This report, combined with the NEM limit, and other legislative proposals, may lead to changes in the NEM law for new projects. Issues to be addressed may include who pays non-bypassable charges on the NEM eligible generation serving a customer's on-site load, and more importantly how it will be calculated.

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10 SCE's Rule 9A Rendering of Bills states, in part, that bills for metered service will be based on meter registrations and meters will be read as required for the preparation of bills. Thus, each month, with minor exceptions, SCE reads its customers' meters to determine the consumption from which to prepare monthly bills. If SCE is not able to read a particular meter, it is allowed to estimate the read and consumption for that billing period according to Rule 17A Estimated Usage. Rule 17A states, in part, that when accurate meter readings are not available, SCE may estimate the customer's usage on the basis of records of historical use. However, this estimation can only take place for one billing period without an actual read being obtained.

PU Code Section 770(d) states, in part, that the Commission shall require any estimation that is incorrect to be corrected by the next billing period except for reasons beyond the utility's control due to weather or in cases of unusual conditions when such corrections will then be based on an actual reading following the period of inaccessibility.

Once the California Legislature takes action on this issue, the exemption status of NEM customers could change. SCE ~~and PG&E~~ suggests that customers may no longer be exempt from non-bypassable charges on their generating facility's output serving on-site load, on a going forward basis, with the possible exception of NEM customers who meet the provisions of Public Utilities Code 2827.7. SCE ~~and PG&E~~ also believes that even these Public Utilities Code 2827.7 exempt customers may not be exempt from all components of the utilities Non-bypassable charges. Such a change, in SCE's ~~and PG&E's~~ opinion, would likely necessitate the need for generation output metering on all new NEM eligible generating facilities in order to accurately calculate non-bypassable charges.

SCE's justification to require the installation of net generation meters extends beyond tariff administration, and has indicated a desire to reserve the right to require them for system monitoring purposes.

DG Customer Position

Many of the non-utility Working Group members oppose a blanket requirement for NGOM and also share a differing opinion on the use of estimation. This opposition is driven by both the additional cost imposed by such metering and the possible intrusion onto a customer's property resulting from such metering. Equally important to some DG customers is the concern that NGOM may be used by the utilities to gather customer confidential and commercially sensitive data.

In essence, these customers believe that NGOM is not necessary in all circumstances and should not be automatically required. They argue that CPUC-approved non-metering alternatives when reliable metered consumption information is not made available should continue to suffice for tariff administration purposes, particularly where the customer does not choose to claim tariff exemption compensation for benefits put to the grid, if determined, or for incentive payments from statewide programs such as the SGIP.

The Rule 21 metering section defers to specific utility billing needs set forth in the specific billing tariffs for tariff administration needs, not the other way around. These parties also note that Rule 21 requires the utilities to first demonstrate a need for NGOM before mandating the placement of such metering on the customer's side of the site boundary. These parties further point to the current language that states that utilities should only require NGOM to administer a tariff "*to the extent that less intrusive and/or more cost effective options for providing the necessary Generating Facility output data are not available*." Some DG customer groups further state that the Point Of Common Coupling metering provision provides the requisite metering configuration for retail service tariff administration.[11]

[11] See Rule 21, Section F.4.

In response to utility complaints of data integration issues and billing complexity, non-utility parties maintain that these complaints do not justify the cost of or the intrusion into non-utility property caused by NGOM. Moreover, where a customer has not opted for the gas cogeneration rate or participated in the SGIP and chooses, as is the customer's right under utility tariffs, to have its bills based on estimated usage, NGOM is not necessary and should not be required. For example, as cited above, all three utilities' tariffs provide for the use of estimated consumption to bill Tail CTC, when reliable metered consumption information is not available. The CPUC has determined that this method is reasonable and has ordered the utilities to use it for billing the DL CRS.[12]

In a related matter, the DG customers disagree with SCE's interpretation of Public Utilities Code Section 770(d) about the use of estimated meter readings for billing purposes, noting the specific use of different terms, i.e., "estimated consumption" as permitted by utility tariffs versus "estimated meter readings" referred to in the Public Utilities Code. They believe that these authorities provide direction for the utility when the existing utility meter is unable to be read, as may occur due to weather or vandalism, rather than mandate a new metering requirement. In that instance, the meter reading may be estimated for that billing cycle.

Further, some of the DG Customers believe the CPUC has determined that such DL customers are responsible for certain non-bypassable charges and has also provided specific direction for utility billing of these charges. Many have concluded that the CPUC has determined that NGOM is not required for the calculation of the DL CRS, contrary to SCE's argument that although the CPUC stated existing utility tariffs are sufficient for measuring and estimating departing load, it is silent that metering is specifically not required.

Relationship of Net Generation Metering at the CAISO level to the Metering Issue

Notably, the Federal Energy Regulatory Commission (FERC) has ordered the exclusive use of a point-of-common coupling meter for Qualifying Facilities (QFs) in California and explicitly forbidden the use of net generation meters by the California Independent System Operator (CAISO).[13]

FERC has addressed the question of whether QFs in California must submit to a CAISO proposed requirement of NGOM. FERC ordered the CAISO to meter QFs only at the site boundary, stating that a requirement of gross metering ("net generation metering") was unfair and unnecessary. This decision binds QFs in California operating under a CAISO Tariff.

[12] See Resolution E-3831. Opinion 3.

[13] The utilities disagree with the relevance of this section. According to SCE and PG&E, the FERC Opinion referenced is not relevant to Rule 21 or other retail tariff provisions.

The CPUC in Decision 01-07-027 also found the CAISO gross metering, (*i.e.*, NGOM) policy unsupportable, stating that the CPUC should not "support the CA ISO's gross load metering policy." Although different terms are used, *e.g.*, gross meter for net generation meter, some DG customers believe the CAISO gross metering proposal is equivalent to the "Net Generation Metering" defined in Rule 21. Some DG customers believe the CPUC and the FERC have thus determined that NGOM is not necessary in all circumstances. The utilities do not claim that NGOM is necessary in all circumstances, and believe that these decisions are of no relevance here. In particular, they note that the issue in D.01-07-027 was whether the CPUC should support the ISO's claim at FERC that certain charges should be based on gross usage, an issue not relevant here.

Some DG customers contend that the planning and operation of the utilities' systems are impacted by: 1) the withdrawal or injection of power from or into their systems; or 2) the installed capacity of the customer generation. The electrical power withdrawal and injection is metered at the Point of Common Coupling and the installed capacity of the customer generation is reported as an element of interconnection with the utility. Accordingly, some DG Customers do not believe planning and operation concerns justify NGOM. Moreover, as noted by FERC in its Opinion No. 464, the WSCC witness stated, "[S]ince the implementation of PURPA, QF facilities have typically used [point of common coupling] metering" and he acknowledged that there had been no major system disturbances.[14]

If NGOM Is Required, What Grade of Meters Should Be Required?

Most customer generation facilities are supplied with a meter or other instrument to measure the amount of power produced by the generating facility. Such measurement devices may or may not be of utility grade accuracy but typically satisfy DG customer needs. The data provided by such metering is produced in various formats and quality.

Utility Position

The utilities assert that a revenue-quality meter is required for assessment of revenue-related costs, including customer responsibility surcharges such as public purpose program charges and nuclear decommissioning and other non-bypassable charges. The utilities in particular cite the need to assess these specific charges as a basis for requiring revenue quality meters. The utilities further contend that, due to the

14 See 104 FERC ¶ 61,196, paragraph 39.

uncertainties in accuracy and the incompatibility of data formats, installation of a billing-grade meter is required to measure the output of the customer's generator for acquiring data needed for the operation and planning of their electric systems.

Rule 22's Direct Access provisions for electric meter service providers (Meter Data Management Agent (MDMA) and the Direct Access Standards for Metering and Meter Data (DASMMD) could provide a model for establishing metering standards for third-party meters. Vendors could incorporate these standards as part of the DG configurations they supply to DG developers/customers. These meters would be of a Commission/utility acceptable revenue-quality, utility-grade. This would alleviate the need to install a redundant utility meter adjacent to the vendor's meter.

Appendix B prepared by PG&E provides a comparison of utility-supplied metering costs and functionality. This table includes the meter component only. Typical costs for meter installations including mandated federal taxes vary depending on the voltage of the installation and the size of the generator. Typical costs for installations at the 0 to 600V level would be approximately $1500 while costs for a 21kV installation would run approximately $15,000.

DG Customer Position

Some non-utility Working Group members respond to the utility position that the planning, operation and billing accuracy needs mandate a billing-grade meter by again noting that the utilities' systems are impacted by: 1) the withdrawal or injection of power from or into their systems; or 2) the installed capacity of the customer generation. The electrical power withdrawal and injection is metered at the Point of Common Coupling and the installed capacity of the customer generation is reported as an element of interconnection with the utility. Accordingly, these parties state that planning and operation concerns do not justify NGOM in the first place.

Moreover, the imposition of a requirement for billing-grade meters, if DG developers and DG customers are financially responsible for installation, maintenance and operation of the meters, would add redundant costs as the DG systems already come with meters or measuring devices. DG manufactures and project developers believe that this requirement would increase the costs of DG systems and possibly inhibit DG development.

Pricing impacts and space constraints are important in the treatment of metering issues, particularly for 208 Volt and 480 Volt net generation output meter installations. In general, higher voltage utility metering sections can be much larger and more expensive than the items described below. For example, installation of revenue-grade metering equipment at a 13.8 kV level imposes an additional cost of approximately $30,000.

To provide some perspective on the space constraints and costs of utility meter section installations, most DG applications are installed in existing buildings, the cost and floor print of the meter sections is to be reviewed. This is under review if the DG owner has redundant metering abilities installed on-site, and the utility meter appears redundant. 200A in-line meters are small to install, and can be wall hung in a relatively small space. The equipment costs to install the meter panel can be approximately $1,500. The costs of the utility meter and fees can add an additional $2,500.

Meter installations of 400-800 A require an additional switchboard section that can add up to 38" of switchboard width. The installed cost of this additional section can range from $2,000-3,000, with utility meter fees running an additional $2,500. Meters that are 1000-3000 A are even more expensive, sometimes being more than double the cost of 400-800 A meters.

If Metering Is Required, May Non-Utility or Third-Party Meters Be Utilized And Which Party Is Responsible For The Expense?

Some parties assert their ability to install metering that will meet both the utilities' needs as well as the needs of the customer generator. All parties agree that this and the CPUC companion proceeding are the appropriate forums to consider any needed protocols for third party metering services, perhaps establishing a new proceeding before the CPUC based on Rule 22 metering service provisions. Notably for "net energy metering" projects, the Public Utilities Code establishes cost responsibility for additional meters. Similarly, CPUC Decision 01-03-073 states that the cost of monitoring SGIP program participants will be paid with SGIP funds.

Utility Position

The utilities believe the costs associated with any DG interconnection, unless specifically waived by statute, should be borne by the DG customer. Other ratepayers should not be burdened with another customer's choice related to electrical service. However, the metering required for the self-generation incentive program, if not otherwise required, are paid for out of the SGIP budget, rather than by the DG customer.

PG&E recommends that for all gas fired cogeneration DG customers that qualify for PG&E's gas rate for electric generation (G-EG) a net electric generation meter be required. An explanation of why a NGOM is required is detailed in Appendix A. ~~PG&E recommends that in all cases where the IOU is a combined utility, all gas fired cogeneration DG customers that apply for gas transportation service under the provisions of that utility's electric cogeneration rates, a net electric generation meter is a~~

~~required.~~ Such metering will be installed and owned by the IOU and the costs of such meter installations will be borne by applicant. If the IOU only provides electric or gas service, if metering is required, the utilities prefer to own and operate the meters themselves, with the DG customers responsible for the costs of owning, operating and maintaining the meters. The utilities are, however, willing to consider third party provision of metering services if proper controls for DG customer data accuracy and security are implemented, and the utilities are able to integrate the data provided into the various utilities' billing systems.

In the event that the CPUC reopens, per the template set forth in Rule 22's Direct Access provisions for electric meter service providers (Meter Data Management Agent (MDMA) and the Direct Access Standards for Metering and Meter Data (DASMMD) the issue of third-party meter ownership, it makes sense that any meter standards be communicated to vendors such that the meters they install as part of the DG configuration supplied to developers, customers, or both, be a revenue-quality, utility-grade meter. This would alleviate the need to install a redundant meter.

Utilities recognize the additional incremental cost of having to install utility owned and operated meters may affect the economics of new DG installations. However, the utilities believe the initial costs are insignificant to the on-going administrative costs placed on the utilities and the host customers after customer generation is installed. At this time, there remain significant technical and process hurdles to overcome with any future third party ownership issues. Most important of these is the difficulty in electronically linking third party meters with, and the transfer of data to, utility billing systems efficiently. This means accurate and timely data management that minimizes resources, preserves customer confidentiality, and maintains data veracity.

PG&E is very concerned about the significant hurdles which must be overcome prior to the allowance of future third party meter ownership, paramount of which is the difficulty noted above in electronically linking third party meters with utility billing systems. As noted above, PG&E uses data from net generation meters for gas and electric billing, proper rate application, and compliance monitoring. According to PG&E, it is in the interest of all ratepayers to maintain accurate metering data. Therefore, PG&E recommends these meters not be installed or owned by 3rd parties

DG Customer Position

While some non-utility parties agree that Rule 22-type metering provisions would provide a basis for protocols for third party metering services, they assert that the current Rule 21 language already permits the CPUC to allow third-party provision of metering services for metering.

Some non-utility parties are concerned about the costs of a redundant metering requirement where a third party provider or customer has already installed a billing-grade meter. These parties believe that the installed meter currently meets utilities specifications and allows access to tariff-approved billing data. For these customers, a requirement for a utility-owned meter would impose an additional $4,000 - $10,000 to the installed cost per project.

Synergizing the Results of this Proceeding with the Cost-Benefit Work Being Conducted CPUC Proceeding R.04-03-017

Much work is yet to be done related to the costs/benefit analysis conducted as part of the CPUC's companion rulemaking R.04-03-017 and the ultimate metering needs for purposes to properly measure costs and benefits of DG are unknown at this time. Furthermore, the CPUC's advanced metering infrastructure proceeding (R.02-06-001) and advances in electric system operations may or may not require additional metering.

For these reasons, the metering recommendations contained in this report must be flexible enough to accommodate today's metering requirements as well as future requirements resulting from other proceedings that are not yet complete.

DISPUTE RESOLUTION PROCESS

Is the language contained in Section G of Rule 21 adequate to resolve differences between utilities, customers, or other parties planning, and designing DG installations?

Are other approaches preferable, i.e., the process adopted in the Massachusetts DG Investigation DTE 02-38-B?

Rule 21, Section G sets forth the following procedures for addressing disputes that arise under Rule 21:

- The CPUC has initial jurisdiction to interpret or modify Rule 21 or any interconnection agreements entered into under Rule 21 and to resolve disputes regarding a utility's performance under its interconnection tariffs, agreements and requirements.
- Disputes between a producer (*i.e.*, the entity that enters into an interconnection agreement with a utility) and a utility regarding the utility's performance under its interconnection tariffs, agreements and requirements are to be resolved using the following procedures:
- The aggrieved party is to notify the other party in writing of the known facts relating to the dispute, the specific dispute and relief sought, and express notice by the aggrieved party that it is invoking the Rule 21 dispute resolution procedures.
- The parties must meet and confer to try and resolve the dispute within 45 calendar days of the date of the dispute letter.
- If the parties do not resolve their dispute within 45 calendar days, the dispute will, upon demand by either party, be submitted to the Commission for resolution in accordance with the Commission's rules relating to customer complaints.
- Pending resolution of a dispute under Rule 21, Section G, the parties are to proceed diligently with the performance of their respective obligations under Rule 21 and any interconnection agreement.

Most parties believe that the dispute resolution process can be improved to some degree. ~~PG&E supports the use of the existing Rule 21, Section G as a starting point from which to create a revised Rule 21 section on dispute resolution.~~

Before addressing what portions of the process might be modified, it should be noted that SCE feels the current dispute resolution process being used in California can also be used to resolve DG issues. A DG customer can file a complaint with the Commission for any infraction of a Rule or Tariff. Thus, according to SCE, any infraction of Rule 21 can be resolved by the current dispute resolution process.[15]

Review of Other Approaches

The Rule 21 Working Group had suggested that the newly-developed Massachusetts dispute resolution process also be considered. All parties are against this approach at this time. The Massachusetts model, touted by many in the DG industry, has only recently been created and has not been utilized to date. Furthermore, the terms and conditions within that proposal add to the burden rather the making dispute resolution more efficient for all parties. Appendix C compares the general provisions of the Rule 21 and the Massachusetts processes as they currently stand.

The option for a DG customer to approach the Rule 21 Working Group with an issue was also discussed at the workshop. PG&E's position is that this option should not be formally incorporated into the Rule as a requirement, preferring for it to be an informal option for the customer. PG&E recognizes several problems with formally requiring this step in the Rule: not all DG customers have access to the working group meetings, whether for financial or time considerations, given that the meeting locations alternate among the utilities and the Energy Commission. Further, PG&E notes that the timing of the meetings, typically held once a month, might not allow timely consideration of a dispute. In addition, some issues are specific to the developer, rather than involving more generic issues that are usually addressed by the Rule 21 working group.

Based on the above discussion, the Working Group does not suggest using an approach that differs from the existing dispute resolution process contained in Rule 21. However, there is potential room for improving the existing process, as evidenced below. Before beginning that discussion, we offer two brief case studies of two projects in the PG&E service territory where the process was invoked. Problems arising from that experience have largely influenced the recommendations contained in this section. The Working Group wishes to express~~es~~ its specific gratitude to RealEnergy, Tecogen, and PG&E for sharing their experiences in this report.

15 SCE notes that the informal complaint process involves several steps all with the goal of resolving the complaint before it becomes a formal complaint. In 2003, SCE received approximately 4,000 informal complaints from customers with six becoming formal complaints. SCE continues by stating the other utilities have had similar successes with the process. The Informal Process involves supervisory review by the utility, review by the CSD Branch of the Commission's Energy Division, and combined review by impartial utility and CSD representatives which can also include mediation or arbitration at the customer's request. There are timelines for each step of the process with steps one and two being no more than 10 days and step three no more than 15 days. The Formal Complaint Process is handled by an ALJ pursuant to Resolution ALJ-1263 and the Commission's Rules of Practice and Procedure which have established time lines that result in a timely issuance of a Formal Complaint Decision.

RealEnergy Dispute Resolution Experience

In early 2003, RealEnergy submitted applications to interconnect three projects with PG&E's "spot" network in San Francisco. During interconnection discussions, PG&E consistently proposed requiring that 15 percent of the total nameplate rating of PG&E's transformer be imported during a building's minimum load period. This proposed requirement would have precluded RealEnergy from developing any projects in San Francisco.

The 15 percent transformer import requirement was not contained in Rule 21 or PG&E's Interconnection Handbook. In fact, Rule 21 provides, for radial systems, that the minimum power import requirement is five percent of the generating facility's gross nameplate rating.[16] PG&E had previously (in 2001) applied the five percent generating facility standard to a RealEnergy "spot" network project in Oakland. No safety or reliability problems have arisen at this location.

Despite numerous requests from RealEnergy over a period of approximately eight months, PG&E was unable to supply RealEnergy with a regulatory or technical justification for the 15 percent transformer input requirement or explain why it was seeking to impose different standards on similar "spot" network projects. On September 15, 2003, RealEnergy invoked the Rule 21 dispute resolution procedures and sent PG&E the required written notification.
RealEnergy and PG&E met and conferred within 45 days of the date of RealEnergy's letter. However, the process was not concluded until December 2003. RealEnergy did not file a complaint with the Commission.

RealEnergy identified the following issues with the Rule 21 dispute resolution process as a result of its experience with PG&E:

- Time was wasted trying to ensure the appropriate utility staff participated in negotiations.

- There is a tendency by the utility to interpret Rule 21, Section B.9 as imposing an inviolable duty to ensure safety and reliability, even in the face of verifiable data from the producer or a utility's technical staff or consultant demonstrating a particular interconnection poses no threat to safety and reliability. The result is that Section B.9 becomes a barrier to entry.

- If neither party chooses to file a complaint, there is no timeframe for concluding informal discussions.

- Because filing a formal complaint is costly and time consuming, the current Rule 21 dispute resolution process effectively limits dispute resolution to

16 RealEnergy understands PG&E has prepared a white paper proposing standards for interconnecting projects to "spot" networks. It is not clear how PG&E intends to incorporate those standards into Rule 21.

informal discussion between the developer and the utility and precludes development of a record for a neutral decision-maker through an interim process, such as CPUC Energy Division review, in cases where it may be useful to do so.

Tecogen's Dispute Resolution Experience

Tecogen's recent dispute with PG&E began when PG&E rejected a group of Tecogen applications for "Simplified Interconnection" despite the full certification of the product and the site-specific Rule 21 screens being passed. Instead, the Tecogen applications were sent to "Supplemental Review" for further study. The applications were returned with a new requirement: each site would require a second and completely redundant system of safety relays that followed PG&E's own internal design interpretation and criteria. The situation affected about 24 units and 15 sites in the PG&E territory.

No resolution was forthcoming, despite numerous Tecogen/PG&E meetings and vigorous debate of the issue at the Rule 21 meetings. The requirement for the redundant system was crippling to the project costs and Tecogen had little choice but to press for a more favorable outcome. Tecogen considered following the formal process of a CPUC complaint but decided to follow this route only as a last resort due to expense, time, and difficulty this would impose. In the end, after much internal discussion we took the path of appealing to the highest management levels within PG&E; a letter outlining our position was sent to the PG&E board of directors. Consequently, a compromise agreement was reached that still required our certified units to have a redundant safety relaying system. However, the redundant system was a less costly one than originally specified by PG&E.

The entire process was unsettling in many ways. The time required caused extreme stress on the company financially (inventory expanded as units became stranded in the field and in the factory). PG&E was extremely slow in transferring the verbal agreement to paper (six months passed from our "handshake" to written one-page agreement). More importantly, the most progressive aspect of Rule 21, the creation of a system that allows type-testing and pre-certification for utility interconnection, had been severely undermined. Tecogen remains extremely concerned that the agreement will be undone by proposed changes being put forth by the utilities due to the low participation of non-utility entities in the working group sessions.

PG&E Response to the RealEnergy/Tecogen Comments

PG&E agrees that it has spent a good deal of time and energy in negotiations with RealEnergy and Tecogen, although it disagrees with many of the specific statements by both parties above. PG&E notes that it included a number of technical and management personnel in this dispute resolution process. All affected projects were ultimately interconnected. One of the issues involved with RealEnergy was a technical issue concerning interconnection of DG with network systems, which is a topic under review by many utilities across the country.

As Section V of this report correctly observes, there is a great deal of work that needs to be done concerning the installation of DG on such systems. PG&E is proud of the fact that it found creative ways of making DG work on such networks, and is learning as it moves forward. The utility does not believe that the resolution of disputes with either party in any way indicates the need for changes to the dispute resolution process under Rule 21.

Recommendations for Improving the Dispute Resolution Process

In order to ensure the Rule 21 dispute resolution process affords a meaningful opportunity to resolve issues before resorting to the formal complaint process, parties interested in revising the process have several suggestions. Some of the suggestions are generally supported by all parties, while others are clearly not.

As the Committee considers these recommendations, a number of observations should be noted. First, from the perspective of the DG customer, there is little financial/time incentive to reach settlement from the utility prospective, while the opposite is almost certainly the case for the developer. Also, many of the dispute processes remain severely impeded by generalized and weakly supported utility arguments based on safety/reliability. From the utility perspective, there are legitimate reasons for uniquely treating the same type of DG installation in different locations, due to different loading and other factors concerning the distribution lines in the area.

Consensus Recommendation #1: Upon receiving written notice that the dispute resolution process is being invoked, each party to a dispute initiated pursuant to Rule 21 must designate one or more participating representatives with the authority to make decisions necessary to resolve the dispute. Technical or support staff must be simultaneously designated to assist with that determination.

Parties disagree about when such designations should occur. RealEnergy has proposed a five-day process whereas PG&E has suggested 10 days in order ensure availability for an appropriate decision-maker. Tecogen also sees the value of a finite timeframe recommending a timeframe not exceeding 2-3 weeks. In addition, PG&E does not agree that it should be required to designate a technical or support person, let alone do that in five days. In many cases, it believes that no such technical person will be necessary.

Consensus Recommendation #2: If parties are not able to resolve a dispute within an initial 45-day period, they may continue negotiations. Alternatively, either party may request in writing that the Energy Division provide assistance in resolving the dispute.

The other party may also provide the Energy Division with its summary of the dispute. The Energy Division shall have 45 days from the date of the written request for assistance to meet with the parties in an effort to assist resolution of the dispute.

This recommendation is supported by all parties. In addition, PG&E proposes to add the language in bold: ".... provide assistance in resolving the dispute, **or, by mutual consent, parties can select a mediator.**"

Consensus Recommendation #3: If the dispute may not be resolved with the assistance of the CPUC Energy Division, either party may file a complaint with the CPUC. All parties support this suggestion.

Disputed Recommendation #1: Utility must provide producer with reasonably detailed technical or regulatory justification for interconnection requirements it proposes to impose. It may not rely solely on a general assertion of need to protect safety and reliability as provided in Section B.9 of the Rule.

While RealEnergy and Tecogen support this recommendation, PG&E opposes this in its entirety. According to PG&E, utilities must be free to justify technical requirements on the grounds that it is needed for safety and reliability when that is true. To do otherwise would gut their discretion to protect the system. Moreover, the purpose of dispute resolution procedures is to set forth substantive mandates for settlement. This is trying to write substantive Rule 21 interpretation guidelines into the dispute resolution and is entirely inappropriate.

Disputed Recommendation #2: To the extent resolution of a dispute may have application with respect to future projects of the involved DG producer, the resolution shall apply to such future projects, unless the producer and the utility mutually agree otherwise.

Similar to the previous disputed recommendation, PG&E strongly opposes this recommendation. It believes it is impractical to suggest in the body of Rule 21 that resolution of every dispute with one generator can apply to all future projects. The utility argues that, because circumstances can change from project to project, depending on local line loading and design, and the technology involved, what happens to one project may not in fact resolve what happens to another project that may think it is similarly situated, but in fact, is electrically distinguishable.

Disputed Recommendation #3: The results of each dispute resolved pursuant to Rule 21 shall be made publicly available.

RealEnergy and Tecogen strongly support this recommendation. The resolution should be precedent-setting for other projects that any reasonable third party would consider similar, especially in cases like Tecogen's where the dispute involves the applicability of Rule 21 certification and type-testing (the logic for this seems self-evident). Also, the utilities should have to present reasonable explanatory support of their arguments (rather than making blanket unilateral general assertions about safety and system reliability). The CPUC filing as the "court of last resort" so to speak is likewise self-evident as is the need for dispute records to be publicly available.

PG&E offers a different perspective on the recommendation. Absent signing a confidentiality agreement, customers are free to publicly disclose the fact that they have had a dispute with the utility. Unless the customer has publicly disclosed such information, utilities are usually required to keep customer-specific information confidential. In most cases, disputes with utilities are resolved without the need for disclosing such customer information. The CPUC should reject this proposal. Furthermore this runs counter to the CPUC's current rules on settlement of disputes (Rule 51) which recognize the important role of confidentiality in settlement discussions – if this is added, it will reduce the number of settlements and lead to more formal complaints.

INTERCONNECTION INITIAL AND SUPPLEMENTAL REVIEW FEES

The Committee needs input from the parties about the need to revisit the interconnection fee schedule.

Since Rule 21 was completely revised in late 2000, DG customers seeking to interconnect to the grid have been subject to a maximum fee of $1,400 as long as the project qualifies via the Initial or Supplemental Review process. The projects requiring little evaluation are assessed $800, with an additional $600 charged if some but not a substantial level of additional review is required. A project qualifying for interconnection under this provision is generally granted approval within 20 days, subject to an application being completed.

Projects that are more complex often fail the Initial and Supplemental Review processes, requiring a comprehensive review or a detailed study. Before doing so, the utility provides the customer with an estimate of the study and any approximate dollar amount for expected protection equipment.

When the fees were adopted in late 2000, the CPUC left open the possibility of revisiting the fee issue at a later date. What was clear then was that the actual cost of processing the interconnection application exceeded the fee being collected by a significant amount. At the time of the decision, it was assumed that the cost of reviewing the application would decline over time with developers and utility protection engineers becoming more familiar with the equipment and the process for assessing DG interconnections.

Two significant attempts have been made to analyze interconnection review costs. Under the Energy Commission's FOCUS contract, an analysis was taken to determine whether the time and cost of interconnection have declined with the implementation of the new Rule 21. The report concluded that, from the customer's perspective, the time and cost did indeed drop significantly. Most interconnections are now achieved through either Initial or Supplemental review. The average time from application to interconnection dropped from 300 days in 1998 to less than 75 days in 2003, and continues to drop. The cumulative value realized from streamlining the interconnection process (Years 2001-03) is over $20 million, largely from savings in time and reduced interconnection costs.[17]

Analyzing costs from the utilities' perspective was more challenging, with limited directive from the Energy Commission and the CPUC towards reporting the costs. In late 2002, the CPUC did order the utilities to track DG interconnection review costs and

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17 Source: *Making Better Connections: Cost Effectiveness Report on Interconnection of Distributed Generation in California Under the Revised Rule 21:* Energy Commission Publication 500-04-044, published July 2004.

report in early January 2003. All three utilities complied with this request and concluded that the costs far exceed the fees being collected. PG&E took this request one step further by creating an interconnection tracking system, which it continues to use today.

During the course of the September/October meetings, the group discussed a DG Interconnection Cost Matrix prepared by PG&E, shown in Table 3. The table provides what PG&E describes as average interconnection cost data for 2004, annualized based on data through August. As the table indicates, the average cost of an interconnection review varies widely depending on the complexity of the project. For the simplest of the projects, a standard net metered project (i.e., PV on a residential home), the average cost of interconnection is less than $900. In contrast, traditional Rule 21 applications indicated in the last column average nearly $29,000. It should be noted that the unit costs overstate the actual costs of a completed application since the numbers include costs incurred for all applications, including those that are withdrawn. For example, for non-NEM applications, PG&E estimates that one-third of applications are withdrawn.

TABLE 3
PG&E DG INTERCONNECTION COST SUMMARY FOR 2004
TOTAL PROGRAM COST: $5,091,000

Rule 21 Technology	Administration	Engineering Review (Initial/Supplemental)	Pre-Parallel Inspections	Totals
Standard NEM Total Projects: 2,949 Total MW: 12.30	Cost: $1,263,000 $428 per project $102,683 per MW	Cost: $134,000 $45 per project $10,894 per MW	Cost: $1,150,500 $390 per project $93,53 per MW	Costs: $2,547,500 $864 per project $207,114 per MW
Expanded NEM Total Projects: 188 Total MW: 8.25	Costs: $312,000 $1,664 per project $37,818 per MW	Costs: $59,000 $315 per project $7,152 per MW	Costs: $88,500 $472 per project $10,727 per MW	Costs: $459,500 $2,451 per project $55,697 per MW
Non-NEM Projects Total Projects: 72 Total MW: 62.85	Costs: $1,192,000 $16,556 per project $18,966 per MW	Costs: $130,000 $1,806 per project $2,068 per MW	Costs: $762,000 $10,583 per project $12,124 per MW	Costs: $2,084,000 $28,944 per project $33,158 per MW

Notes on Table:

1) Data reflects PG&E's **Distributed Generation and Distributed Energy Resources OIR, DG Cost Benefit Analysis,** testimony as filed in CPUC Rulemaking R.04-03-017, on 10/4/04.
2) The costs reflect actual DG-related interconnection costs tracked by PG&E from 1/1/04 through 8/31/04 normalized to calendar year 2004, up to the time of interconnection. Note that in 40 percent of the non-NEM projects, total costs include customer payments.
3) Administration costs reflect costs associated with the processing of the applications and requisite interconnection agreements, as well as the setting up of the billing and database tracking for NEM applications. ~~Expanded NEM and non-NEM applications did incur additional costs for legal and tariff support activities due in part to their larger size and higher likelihood of system impacts.~~
4) Costs associated with biogas NEM and fuel cell NEM applications are not addressed, nor are the costs associated with performing detailed interconnection studies, nor the costs for installing distribution system improvements and/or interconnection facilities.
5) ~~"Distribution System Improvements" are facilities required to interconnect a DG project other than Interconnection Facilities (see Note 6), and are paid for by the utility.~~
6) ~~"Interconnection Facilities" are those facilities that only benefit the customer/DG generator, and notwithstanding the interconnection of the DG would not have been undertaken by the utility.~~

The distinction in cost among the three rows was debated extensively. Some of the discussion focused on the pre-parallel inspection average cost of $10,583 and the rationale for the cost being so much higher than the inspection in the other categories. PG&E had indicated that it was often necessary to send utility representatives to multiple inspections for the same project, due to circumstances sometimes under utility control, sometime under customer control, and sometimes not under the control of either party. While PG&E's numbers provided a good starting point by which to start the discussion, many other parties felt the estimates were overstated for a variety of reasons. The Working Group is not in a position to debate this contention and expect this specific issue to be addressed when the CPUC holds hearings in R.04-03-017 in March 2005.

Another portion of the debate focused on whether the fee was low enough to discourage serious DG projects from being developed while being high enough to keep non-serious projects from taking limited review time from utility protection engineer as well as utility administrative support. The developers actively participating in the meetings indicated that the fee is reasonable and should remain at its current level.

Ultimate changes to the fee structure will likely require a revisiting of the fundamental issue about whether the interconnection review process should be subsidized by utility distribution customers as it is presently or whether the customer should bear the entire cost of the review. By virtue of the discussion in the Working Group meetings, many DG could not afford to pay the entire bill.

Recommendation

While some parties have chosen not to offer a specific position on the issue, the general feeling of the majority of the Working Group is that there is no need to change the fee structure at this time. However, there are certain things that need to be further investigated, some of which will be undertaken as the CPUC considers the cost-benefit issue during the hearing phase of R.04-03-017.

PG&E suggests a change in the cost responsibility for pre-parallel inspections for Rule 21 non-net-energy metered interconnections. From the previously submitted PG&E 2004 DG Cost Matrix, it can be seen that significant expenditures have been incurred for pre-parallel inspection activities. PG&E recommends that a more equitable balance may be achieved by requiring that any pre-parallel inspections after the first attempt be the cost responsibility of the party responsible~~applicant~~. Other parties have objected to this recommendation, stating that it is not always the fault of the applicant when multiple pre-parallel inspections are made. PG&E agrees, and does not seek to charge the DG customer if the subsequent inspections are required due to utility error. However, if the DG equipment is not ready for inspection when the utility sends its crews to inspect, then the DG customer or vendor should pay for the cost of that trip. PG&E's experience with non-NEM interconnections is that the customer is typically not ready to interconnect on the first inspection trip. Multiple trips contribute to the high per project cost for inspections reflected in Table 3.

To reconcile some of the concerns that parties had about PG&E estimates being overstated, it could be useful to develop ~~is imperative that~~ a consistent tracking and reporting system ~~be established~~ to improve the value of the data going forward. Detailed data on interconnection costs will allow regulators to better understand cost causation and allocate these costs to the appropriate parties, depending on the results of the cost/benefit work currently being undertaken. However, a specific proposal has not been developed for discussion by the Working Group.

NET METERING FOR SYSTEMS WITH "COMBINED" TECHNOLOGIES

> *The passage of ~~California Assembly Bill 58 (Statutes of 2002)~~several bills has expanded the net metering program to include larger systems and technologies that are not just photovoltaic and wind. [Some of these were not created by AB 58.] Fuel cells and biomass projects are now eligible for net metering consideration on a pilot basis. Customers who install generation that include generators eligible for net metering coupled with generators not eligible for net metering create challenges with respect to logging the costs of reviewing the interconnection application, metering requirements, and associated tariffs. The Committee understands that this issue is a growing concern among the utilities and would like further elaboration on the topic.*

In response to the direction provided by the Committee in its scoping order, the Rule 21 Working Group has engaged in further discussions regarding logging of costs of reviewing applications, metering requirements and tariff administration associated with the integration of both NEM and non-NEM generators. Based on extensive discussions, the Working Group offers the following conclusions and recommendations to the Committee for its consideration:

- Interconnecting multiple-technology generators on the customer's side of the meter, whether for a generalized DG facility or a generating facility using generators which would be eligible for interconnection under NEM tariffs does not present any insurmountable technical obstacles that would preclude the effective operation and protection of the utility distribution system.

- For cases involving multiple NEM generators allowed to export under different NEM tariffs, a metering solution may be workable provided that tariff administration issues can be worked out.

- In the context of the Rule 21 Working Group's review of the interconnection of a combined technology generating facility to the grid, policy guidance is required on the appropriate limits to be placed on exports from such a facility. Also, issues remain in the areas of tariff administration, equitable allocation of study costs, interconnection costs and tariff charges.

- Policy issues remain to be resolved regarding how the fundamental intent of the NEM program as established by the California Legislature should appropriately be carried out with respect to peak reduction, self-consumption, overall societal cost and economic dispatch. The Legislature is scheduled to receive a report on January 1, 2005 from the CPUC addressing many of these issues.

The following discussion elaborates on these conclusions and recommendations, offering potential solutions to the technical, contractual, and tariff-related problems of the combined technology interconnection.

By way of background, NEM customers that have a ~~single~~ PV technology-based generator that is under 1 MW receive the following benefits under NEM: 1) departing load, non-bypassable charges, and standby charges are not applied to the output of the generator; 2) interconnection reviews are performed free of charge; 3) credits for any power produced in excess of load during a year are applied at the full retail rates; and 4) the two-way flow of power is unconstrained. Fuel cell and dairy biogas projects receive a credit for excess power based only on the generation component of their tariff. Dairy biogas customers also have the right to aggregate retail loads at other dairy operation related sites located on the same property to receive the benefit of the credit for excess generation.

Section 2827 does not address a customer who installs a qualified NEM technology with other non-NEM technologies, such as fossil fuel cogeneration. It also does not address how generators of two different technologies, each eligible for a different NEM tariff, are to be combined.

The issue of assuring proper tariff administration with a combined installation of NEM and non-NEM generators was addressed in principle by the CPUC in the first DG OIR (R.99-10-025).[18] The CPUC set forth the position that "integrated use of nonrenewable energy sources [does not exclude] eligible renewable generation connected to the same service account from net metering." The CPUC qualified this position by stating "the ineligible generator does not become eligible for net metering due to the combined configuration."[19]

To ensure that non-NEM generation did not receive the same treatment (and benefits) as NEM generation, the CPUC suggested that Option 1 of Rule 21 (i.e., use of a reverse power relay to ensure that power is not fed back into the utility grid) could be used to "[provide] adequate assurance that a nonrenewable generation system, even when connected to the same service account as the eligible renewable generator, will not export electricity."[20]

The Rule 21 Working Group has identified several scenarios under which an interconnection application might be submitted by a customer, based on the sequencing of installations:

- The NEM generator was pre-existing and an application is made for a non-NEM generator;
- The non-NEM generator is pre-existing and application is made for an NEM generator;

[18] D.03-02-068
[19] Ibid, p. 61.
[20] Ibid, p. 61.

- An application for NEM and non-NEM generators is submitted at the same time;
- Application is made requesting the utility to approve export from the site when the non-NEM generator is in operation.

Each scenario will have unique ramifications with respect to the complexity of interconnection review, additional equipment and testing, and additional metering.

Metering and Tariff Considerations

Combined technology generating facilities may impose special metering requirements beyond those that would apply to a single-technology NEM, to ensure that 1) only energy from an NEM generator is metered for credit; 2) proper credit factors applied where different NEM rates are applicable; 3) ensure that non-NEM generators are metered for tariff administration and distribution system monitoring; 4) for biogas and fuel cell NEM, correct application of biogas generation credit against aggregated retail account. It will also be necessary to assure that other tariffs associated with the combined technology generating facility can be properly administered (e.g., standby and departing load tariffs applicable to non-NEM generation).

Technical Considerations

While D.03-02-068 addressed objectives of encouraging use of NEM while maintaining proper administration of tariffs for NEM and non-NEM generation, it did not address technical aspects of coordinating protective devices for a combined installation. The Rule 21 Working Group has identified a number of issues relating to assuring adequate protection.

When a customer installs any generator, it must interconnect in accordance with Rule 21. The application of Rule 21 leads to three general options for a customer: 1) install relays that will trip the cogenerator off before power is exported to the grid on more than a momentary basis, 2) show that the system design and customer loading will inherently yield negligible or no export and address safety concerns, or 3) pay for and provide additional protective functions that permit safe operation in an export-to-the-grid mode (typically requires the ability to detect faults on the utility distribution system- normally a more expensive design than the two former designs). Regarding Option 1 above, it is essential for safety to utility's electrical workers and distribution system that the customer's non-NEM generator breaker trips open if export is detected for a period longer than the prescribed setting. This prevents the formation of an unintended island under a utility outage condition.

In the absence of a synchronous or induction generator, the certified anti-islanding inverters used in most NEM systems will shut down during a utility outage. However, it is possible that in the presence of synchronous or induction generation, these combined technology systems may not detect the utility outage and cease production since they may not be able to differentiate between power supplied from the utility and power supplied from the cogenerator. This is a safety issue that must be addressed. Potential solutions are discussed below.

Contractual Considerations

Existing CPUC-approved interconnection agreements for DG do not address generating facilities for which multiple tariffs apply. Principles to be embodied in an interconnection agreement for these types of facilities should include the following:

- Non-export (or inadvertent export) limits on non NEM generators should be maintained;
- Insurance provision for Generating Facilities with non-NEM generators should be included;
- Phased installation of NEM and non-NEM generators should be addressed;
- Review and facilities costs for non-NEM generation should be addressed.
- Departing load and standby charges applicable to non-NEM generators should be addressed.

The Rule 21 Working Group has facilitated the development of uniform contracts for several types of non-NEM DG facilities; it is anticipated that it would be a useful forum to assist in the development of suitable agreements for combined technology NEM generating facilities.

Potential Solutions to Metering and Tariff Administration Issues

Given the myriad of combinations of NEM and non-NEM generating configurations, it is important to focus on the solutions for the four scenarios described above. Table 4 provides a summary of each scenario, its rationale, and the issues surrounding implementation of the approach.

TABLE 4 POTENTIAL SOLUTIONS TO METERING AND TARIFF ADMINISTRATION ISSUES FOR COMBINED TECHNOLOGIES		
Scenario/Discussion	Attributes	Issues
1. Non-NEM May Not Operate During Export Under this approach endorsed by the CPUC, if the combined total generation of both NEM and non-NEM generators exceeded total on-site electrical load, the non-NEM generator would trip. Any export power metered at the Point of Common Coupling would, therefore, represent only NEM generation.	Consistent with CPUC guidance. Simple. One or more combined technology projects have been interconnected on this basis already.	This approach will guarantee that no energy from the non-NEM generator could be exported and receive the NEM credit. Under some circumstances, depending on the relative size of the eligible and non NEM generators, it could also prevent the export of NEM energy when the non-NEM generator is operating.[21] To avoid frequent nuisance tripping of the non-NEM generator, the customer can adjust its regulation to ensure that its output remains below the set point of the reverse power relay. This will also prevent the export of any NEM energy when the non NEM generator is running. In a generating facility in which the non-NEM generator was relatively large, this approach could require that the non-NEM generator operate below its full design rating during the times the NEM generator was also operating. This could adversely affect project economics due to the less-efficient use of the non-NEM generator and additional demand charges. Also, this approach does not address the case of multiple generators eligible for different NEM tariffs, in which case all exports would be "eligible"—just treated differently for credits and retail load aggregation if dairy biogas.

21 The likelihood that this alternative will limit exports from the NEM generator depends on the relative sizes of generators and load, as illustrated in the following cases: 1) PV system & non NEM generator: The typical non-NEM generator in the marketplace today is of a larger capacity (kilowatts) than typical PV equipment. Use of a reverse power relay to trip the larger non-NEM generator will effectively result in no export. However, if the PV capacity exceeded the customer's load, this alternative would allow export of NEM energy. 2. Fuel cell-NEM and non NEM: Similar conditions as Case 1 above. 3. Biogas NEM and non-NEM: The generators typically used at biogas facilities tend to be of larger capacity than non NEM generators which might be used at the same facility. Under these parameters, if the biogas generator is larger than the customer's load, then there will be an export of NEM energy when the reverse power relay trips the non-NEM generator.

TABLE 4 POTENTIAL SOLUTIONS TO METERING AND TARIFF ADMINISTRATION ISSUES FOR COMBINED TECHNOLOGIES		
Scenario/Discussion	Attributes	Issues
2. NEM and non-NEM Generator: Allow export while non-NEM generator is operating, up to the limit of the output of the NEM generator. Allow export of energy and tariff credit up to the limit of the NEM generation when the NEM generator is operating. Non-NEM generator operates with trip or governor control to load follow and prevent export above NEM generator value.	Allows maximum size DG for a given site. Most cost effective for customer generator.	May require extra meter costs, reconfiguration costs, spatial impacts, and complex generator controls. Depending on customer load and size of non-NEM generator, this could still require that non-NEM be backed down to part load. Export limit should be the actual recorded energy produced by the NEM generator, rather than a fixed limit equal to its nameplate capacity.
3. Two or more NEM Generators, Multiple Tariffs: Export allowed. For two generators, each eligible for a different NEM tariff, the task would be to distinguish between the exports from each to allow proper application of the differing credits and retail load aggregation (if applicable). This could be accomplished by metering each generator to determine its production.	Allows administration of different rates.	May require extra meter costs, reconfiguration costs, and spatial impacts. Tariff issues: Can a customer take service simultaneously under two NEM tariffs? Or must they choose one? Will the tariffs change over time?
4. NEM and non-NEM generator: Unrestricted export allowed while non-NEM generator is operating, using metering to determine amount of NEM energy to receive the NEM credit. The task would be to distinguish between the energy exported from the non-NEM and the NEM generator to allow NEM credit to be properly applied to the NEM generator only. This would require: a) metering of both the NEM and non-NEM generator; and b) adoption of a protocol to address the relative proportion of energy exported from the generators. In other words, energy from both NEM and non-	Allows NEM and non-NEM generation to operate without curtailment, unlike Alternatives 1 and 2.	May require extra meter costs, reconfiguration costs, and spatial impacts. May also require different system protection. Could entail full-time export of energy from the customer's site, requiring greater complexity and expense of generator protection and interconnection facilities, and often may require a detailed interconnection study. Pro forma interconnection agreements for continuous export from non-NEM have yet to be developed. For the portion of exported energy that is non-NEM, this unscheduled, non-compensated energy would present a challenge to distribution system control, and possibly limit ability of utilities to procure energy and capacity from more environmentally benign sources. The prospect of unlimited energy exports also raises

TABLE 4 POTENTIAL SOLUTIONS TO METERING AND TARIFF ADMINISTRATION ISSUES FOR COMBINED TECHNOLOGIES		
Scenario/Discussion	Attributes	Issues
NEM generators will serve customer load equally up to the point where total generation exceeds customer load. Exported energy will consist of energy from both generators, and should be apportioned to non-NEM and NEM rather than presumed to be all NEM energy.		questions as to whether this type of generating facility would be "net energy metering" as contemplated in the NEM legislation.

A specific item worth noting under Scenario 2 concerns whether the "stacking of resources" may make this type of project and export project rather than NEM. Stacking can be used to describe a situation which could occur where both NEM and non-NEM generators are operating and exporting power to the utility grid. The physical reality is that power exported consists of a mixture of electrons from both generators. When a metering or billing scheme is used that presumes that all exported energy (to the actual production of the NEM generator) comes solely from the NEM generator, the effect is that NEM generation is effectively "stacked" on top of non-NEM generation. The non-NEM generation is thus relegated to serving on-site customer load, while the NEM generation is reserved to obtain the NEM credit.

The utilities believe that proposed preferential "stacking" of eligible generation on top of non-eligible generation under this approach makes it a renewable energy *export* generating facility rather than a *net energy metered* generating facility. It would not necessarily "reduce demand for electricity during peak consumption periods" as encouraged by Public Utilities Code Section 2728 (a), especially since export is anticipated to occur during times other than utility peak load periods (i.e. weekends).

The City of San Diego has a different interpretation. It believes that the stacking order should allow the eligible output to create credits against other usage up to the output of the eligible generator. Using the current NEM tariff a system may be sized at twice the actual load and the net production over a twelve month period will zero the customer usage from the grid. Any excess output over the *annual* usage creates no credit for the customer-generator.

The parties do not agree that resource stacking may encourage uneconomic dispatch. According to the utilities, allowing resource stacking proposed in Alternative 2 appears to encourage an uneconomic dispatch of generation resources from a societal standpoint by some customers (instead of using solar or wind to serve on-site load first—at zero fuel cost—the customer would be encouraged to serve as much load as possible with fossil fired generation first, to "save" renewable generation for export to maximize NEM credit. Moreover, current regulations governing interconnection of customer generation do not impose any conditions on thermal efficiency—i.e., the non-eligible generator could be non-cogeneration. The uneconomic dispatch inherent in this stacking approach also results in greater cost shifting to other utility customers because the effective cost of the "renewable" export energy (i.e. the full bundled utility retail rate) is typically higher than the cost at which utilities can procure renewable resources through a competitive solicitation process. The City of San Diego believes that the efficiency requirements of the cogeneration system would make the project economic compared to distant baseload plants with line losses considered.

Potential Solutions to Technical Issues

It is technically feasible to provide adequate protection and metering for all variations of eligible and non-eligible generators. Rule 21 as it exists allows for evaluation of all interconnections of multiple tariffs. Each application to interconnect would be required to state what the existing condition is (e.g., NEM system already installed), and what the proposed change is (e.g., a non-NEM system to be installed). The utility review will evaluate the impact of the proposed change and prescribe the requirements for the change. Evaluation of multiple tariffs will often require a full interconnection study.

While the process of technical review and approval of combined technology generating facilities is site specific, and also would be affected by the sequencing of installation as discussed in Section C above, the Rule 21 Working Group has developed some preliminary concepts for approaching such a review. The review depends on the a number of variables, including the type of metering used by the NEM generator, whether additional protection is needed to accommodate the export or whether there is a need to limit the export, and whether the generating unit qualifies for simplified interconnection.

Policy Guidance Needed With Respect to Combined Technologies

Based on this discussion, the Working Group seeks policy guidance on two key areas.

First, is the CPUC-recommended policy for interconnecting and metering combinations of an NEM generator and a non-NEM generator with multiple tariffs, as set forth in D.03-02-068, an appropriate basis on which to interconnect such generating facilities? The utilities believe that, the interconnection methodology endorsed by the CPUC is the most practical approach to interconnect the combination of an NEM and non-NEM generator, from the standpoint of balancing the interests of both the individual utility customer who installs the generators and other customers in general. Of the non-utility representatives actively involved in the Working Group, the City of San Diego believes that any methodology which prevents export from the NEM generator while the non-NEM generator is operating is inappropriate as it reduces the economic benefit which the customer might otherwise enjoy under the NEM tariff, and reduces the efficiency at which the non-NEM generator operates.

Regarding the second area, should customers who install combined NEM and non-NEM generating facilities be subject to interconnection review fees or study costs, costs for interconnection facilities or utility distribution system upgrades, and tariff charges (standby and departing load) which would otherwise be applicable to the non-NEM generator, in the absence of the NEM generator? The prospect of combining NEM and non-NEM generators in a single interconnection raises the issue of how to address the fact that NEM tariffs largely exempt customer from interconnection application fees, charges for interconnection studies and interconnection facilities, while non-NEM generators are not exempt from such charges. Setting aside the question of whether the application fee structure currently provided in Rule 21 is reflective of actual costs incurred by utilities in performing the interconnection reviews, it can nevertheless be stated that the review work required to interconnect the non-NEM generator in a combined technology project must still be done, regardless of the presence of an accompanying NEM generator.

The utilities generally agree it is appropriate for utilities to collect application fees and other charges appropriate to non-NEM generators installed in combination with NEM generators in the normal manner set forth in Rule 21 and other tariffs. An alternative opinion offered by the City of San Diego suggests otherwise, suggesting that the Legislature created laws that value DG and renewable generation as general benefit to the citizens. Legislation that supports DG is being made uneconomic to many customers because of the incremental cost for interconnection issues and various tariff charges. The costs for infrastructure improvements needed (as determined by the local utility) to interconnect with the grid should be the responsibility of the utility with the cost recovered through rates.

INTERCONNECTION RULES FOR NETWORK SYSTEMS

What considerations should be given to developing simplified interconnection rules for networked systems in California?

What can be learned from experiences on this issue from other states and/or utilities?

The rules for interconnecting generating facilities to network systems are different compared with interconnections to radial systems. In a network system, there are technical requirements resulting from the design and operational aspects of network protectors not employed on radial systems.

In California, the major network systems are located mainly in the metropolitan areas of San Francisco, Oakland, and Sacramento. Several DG projects have been interconnected to various network systems during the past few years. Due to lack of technical information and clear guidelines, there have been issues with many of these interconnections.

By the current screening process in Rule 21, interconnections involving network systems are advanced to the "supplemental review" stage. Due to the nature of the protective schemes used in network systems, most of the interconnections now require a detailed study. Without interconnection guidelines, utility companies now have to study each project and establish their own interconnecting requirements on a case-by-case basis.

Other Efforts Related to Network Interconnections

A number of focused efforts on developing network interconnection rules and guidelines are being performed throughout the country. In Massachusetts, the Massachusetts DG Collaborative is now meeting on this issue, pursuant to a directive by the Massachusetts Department of Telecommunications and Energy.

Similar to the Rule 21 Working Group process, the Massachusetts DG Collaborative holds regular workgroup meetings, provides background documentation and is in the process of documenting the various network-related issues. They have also begun documenting network system installations of DG.[22] The group intends to address this issue through June 2005 and bring formal recommendations to its Board at that time.[23]

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22 For additional information on the Massachusetts DG Collaborative, please reference the following websites: www.masstech.org/renewableenergy/public_policy/dg/meeting_index.htm, or www.masstech.org/renewableenergy/public_policy/dg/resources/network.htm.

On the research side, the Energy Commission in collaboration with the US Department of Energy, has already approved a new testing program to study network interconnnections. Testing will soon be conducted by Distributed Utility Associates in California as part of the Distributed Utility Integration Test (DUIT) upon completion of the existing phase 1 testing. DUIT plans to invite experts to a network interconnection meeting in New York sometime during the next few months to discuss the issues and near-term solutions related to network interconnection, as well as to define the testing and test facility design that will be needed to further address those issues. DUIT has developed a network primer that describes what a network distribution system is, defines various components, and discusses the characteristics that pose a challenge to the interconnection of DG. We understand the results of that work will be shared with the Rule 21 Working Group and others.

The Energy Commission PIER program has undertaken the monitoring of several DG systems to assess their impact on the grid and vice versa. This program will also include monitoring of actual DG connected to secondary network systems. Preliminary results of this analysis are anticipated to be available in early 2005.

California's Efforts Thus Far – PG&E Guidelines for Spot Network Interconnections

With the largest network system in California located in the Bay Area, PG&E has taken initial steps to address the protection requirements surrounding network system interconnection. Its protection engineers have developed general guidelines, which can be developed more extensively through the Massachusetts and/or the California process. The utility notes that these interim guidelines will be thoroughly debated and may be modified at some point in the future.

1. All of the network protectors on the Secondary Spot Network shall be replaced with Cutler Hammer CM52 network protectors equipped with MPCV relays.

2. Older style protectors (CM-22, MG-8, and CMD) may remain, provided that the network protector relays are replaced with MPCV relays or other PG&E-approved relays, capable of at least 2 set points, one with a time delay, and shall meet the following conditions:

   a) The Generator(s) plus the associated bus and/or cable to the main switch has a transient and sub-transient X/R ratio of nine or less for all operating scenarios.

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[23] The Massachusetts DG Collaborative is part of the Massachusetts Technology Collaborative, the state's development agency for renewable energy.

b) Synchronization of each generator shall be supervised by a PG&E-approved Sync Check relay.

c) In non-fault conditions, the generator breaker must operate in 1.5 minutes or less.

d) Breakers separating all generation must open immediately without any intentional time delay under system fault conditions.

3. PG&E's Division's Planning Engineer shall review network protector relays on the adjacent lines for relay coordination. If relay coordinations are inadequate, the old relays will be required to be replaced.

4. DG Producer will provide all necessary technical requirements as specified in Rule 21, including the protective device settings and frequency/voltage settings.

5. DG Producer will meet the minimum import requirements set forth below:

a) The DG may not operate Parallel Operation unless a minimum number of network protectors are closed. The DG must trip instantaneously when the number of closed network protectors falls below the following the value [select appropriate value from this table]:

Quantity of Network Protectors In Vault	Minimum Number of Closed Protectors Required in Order for DG to Operate
2	2
3	2
4	2
5	3

b) A minimum import setting of ten percent (10%) of the nameplate rating of the largest single network transformer serving the PG&E secondary spot network bus where the DG is installed. Minimum import protection to be accomplished using a redundant PG&E-approved underpower (Device 37) relay or reversed power flow relay (Device 32). A meter with kVA summation of multiple services from the spot network bus is allowed on the common spot network bus through one or more Generators. If PG&E's meters do not support summation and protection requirements, DG Producer shall be responsible for the cost of providing meters capable of supporting summation. If the minimum import is not met, the Generator(s) must trip within 15 cycles to ensure that the Generator(s) trip prior to the network protectors. Redundant protection of the net import minimum power must be provided.

c) A contact must be available on the existing network protectors to provide open/close status to the DG Producer's trip devices via a GE C-30 controller or PG&E approved controller. The cost for controller along with the installation and operating and maintenance costs of the relay/controller will be borne by the DG Producer. The DG Producer shall install and terminate rigid grounded 2-inch conduit, and a pair of wires from the trip device to inside the transformer vault. The location of conduit core shall be reviewed and approved by PG&E.

d) DG Producer will provide 24VDC source from their battery with charging system for GE C-30 controller or PG&E approved controller. PG&E will do the installation of GE C-30 relay/controller or PG&E approved controller in the property owner's transformer vault.

Working Group Recommendations

The Working Group believes that much work needs to be done in this area and recommends that the Committee direct the Rule 21 Working Group to develop network interconnection rules that can be incorporated into the current framework of Rule 21. Any efforts undertaken in California could be coordinated with the work being performed both in Massachusetts and at the DUIT testing facility. We understand that IEEE will begin the process of developing standardized network requirements in 2005 (IEEE 1547.6). In advance of that process, we estimate that preliminary Rule 21 requirements for network systems could be developed during the next 12 months. Once the IEEE standard is complete, which could take 3-5 years, Rule 21 will be revised consistent with the adopted IEEE standard.

If the Committee directs this process to move forward, the Rule 21 Working Group offers a general outline to complete the task. Four objectives are identified: 1) defining the issues (load, fault—Types: Spot, Area); 2) developing Supplemental Review information; 3) determining general requirements and including those results in section D of the Rule, and 4) determining if opportunities exist for simplified interconnection (if so, include in section I). We offer the following eight-step approach.

1. Develop definitions, characteristics, and design philosophies for different types of networks to provide a common basis of understanding

2. Identify network systems in CA
   - Locations
   - Physical characteristics

3. Identify the stakeholders nationwide who may be able to provide information
   - Utilities with network systems
   - DG suppliers
   - Customers on network systems who may be interested in DG
   - Regulators
   - Network equipment providers and other experts

4. Identify and Investigate other Projects and sources of documentation

- DUIT proposed Network meeting and Network-related testing
- FOCUS-III project monitoring network-system DG sites
- Massachusetts DG Collaborative
- PG&E white paper and other technical literature
- IEEE Standard 1547.6 (SCC21 Chairman DeBlasio hopes to submit a Project Authorization Request to the IEEE board for this new activity in the first half of 2005)
- Manufacturer data sheets/white papers

5. Identify and investigate the availability of other Rules and requirements

6. Identify and investigate existing DR on networks

7. Identify problems and solutions
   - Experience from utilities
   - Experience from system integrators

8. Investigate costs of protection schemes and protector rework

NEXT STEPS

This report focused on five key interconnection issue areas: Metering Issues; Dispute Resolution Process; Interconnection Fees/Costs; Net Metering for Systems with "Combined" Technologies; and Interconnection Rules for Network Systems. The issues were debated extensively over the course of four Rule 21 Working Group meetings held in September and October, with feedback provided to the larger group via e-mail and phone conversations.

Based on those deliberations, the Working Group offered the series of recommendations shown in Table 1.

There are several next steps going forward from this point. Table 5 below details these steps.

Table 5
Next Steps

Rule 21/CEC Staff Interconnection Report Release Date	November 10, 2004
Public Comments Due on Interconnection Report Recommendations	November 30, 2004
IEPR Committee Hearing	December 10, 2004
IEPR Committee Recommendations Release Date	Week of January 6, 2005
Public Comment Due On IEPR Committee Recommendations	January 20, 2005
Energy Commission Adoption Of IEPR Committee Recommendations	February 2, 2005

APPENDIX A
PG&E Net-Generation Metering Issue – From Rule 21 Workshop/DG-OIR Proceeding

Area	Tariff	Need for Metering	Data Required for Frequency	Meter Ownership	Notes
Generator gas tariff administration	G-EG/PU Code 218.5~~, QF Verification~~	In ~~order to~~order to determine compliance with tariff requirements and PU Code 218	Total kWh (Monthly)	Utility (unless DG is located in Muni)~~Have allowed customer owned meters in the past~~	~~Calendar-month kWh data is gathered monthly in order to calculate monthly bills and calendar year operating efficiency. Data is also used to validate that usage is less than 250,000 therms/year to establish permanent noncore status and, to meet operating efficiency requirements per PUC Section 218.5~~Monthly kWh data is gathered in order to calculate monthly bills and calendar-year operating efficiency. Data is used to determine cogeneration is meeting the operating efficiency requirements per PUC Section 218.5
	G-EG/Rule 9	In order to ensure timely and accurate monthly gas bills.	Total kWh (Monthly)	Utility	In order to assure timely gas bills, data must be obtained on specified dates (that align with the gas meter read date) within monthly billing cycles and in a format agreeable to the billing system. For new generators that have no PG&E-owned dedicated gas meter, or where there is mixed gas end-use at a customer's plant, net meter data is used to ensure the correct amount of gas is billed under G-EG~~.~~
	G-EG/G-SUR Exemption	Ensure timely and accurate gas bills for mixed-usage customers, and ensure compliance with 218.5 and to correctly apply exemption from gas franchise fee surcharges established under G-SUR.	Total kWh (Monthly)	Utility (~~preferred~~ unless DG is located in Muni)	G-EG customers that apply for cogeneration status are exempt from paying gas franchise fees under schedule G-SUR. Monthly data is required to correctly determine gas volumes that are exempt.~~Where there is mixed gas end-use at a customer's generating facility, net meter data is used to ensure the correct amount of gas is billed under G-EG~~
Standby Tariff Administration	Schedule S - Reservation Charge and Otherwise Applicable rate Schedule - demand charge	No metered data required, see Notes column	None	N/A	Standby demand charge waiver is provided under conditions of standby agreement (Form 79-280). Reservation Charge & Otherwise Applicable Rate Schedule demand charge
	Schedule S, Special Condition 7	Net generation profile is used to determine when customer is generating at above load requirement.	Net generation profile metering	Utility	This is an option under Schedule S. Customer opts to be billed for "supplemental" and "back-up" service.
	Schedule S and PU Code Section 353	To determine compliance with tariff provision Standby charges~~ - exemption from CTC~~.	Total kWh (Monthly)	Utility (preferred)	Calendar-month kWh data is gathered annually in order to calculate monthly~~calendar-year~~ operating efficiency.
Non-bypassable charges (CTC, PPP, ND, TTA)	Preliminary Statement, BB, and PU Code Section 372	To determine compliance with tariff provision - exemption from CTC charges	Total kWh (Monthly)	Utility (preferred)	CPUC Resolution E-3831 and D. 03-04-030: method found in Preliminary Statement BB to be used to calculate departed load. However, for generators that meet only a portion of the load requirement, metering output is the most accurate means of determining departed load. Other interconnection scenarios (e.g. OTF, or where there is no load history) make this method meaningless.
Cost Responsibility Surcharges (CRS's)	E-DCG	To determine compliance with tariff provision - exemption from CTC charges, DWR Bond, DWR Power, and Regulatory Asset (RA). The RA will change to a Dedicated Rate Component (DRC) effective 2/1/05	Total kWh (Monthly)	Utility (preferred)	CPUC Resolution E-3831 and D. 03-04-030: method found in Prelim. Statement BB to be used to calculate departed load. However, for generators that meet only a portion of the load requirement, metering output is the most accurate means of determining departed load. Other interconnection scenarios (e.g. OTF, or where there is no load history) make this method meaningless.
Self-Generation Incentive Program (SGIP)		Annual efficiency calculation requires calendar month kWh net gen production.	Total kWh (Monthly)	Utility	Where required per the Self-Generation Incentive Program; and all costs borne by the SGIP
Distribution System Operation and Maintenance	Rule 21, Section F.5	Operation and maintenance of the distribution system requires knowledge of generator operation status	Net generation profile metering (data accessed in real time)	Utility	Telemetering required between generator metering and local distribution system operator, for customer generating facilities greater than 1 MW; or generating facilities greater than 250 kW on less than 10 kV systems.
Transmission System Operation and Maintenance	Rule 21, Section F.5	Operation and maintenance of the transmission system requires knowledge of generator operation status	Net generation profile metering (data accessed in real time)	Utility	Telemetering required between generator metering and local switching center, for customer generating facilities greater than 1 MW.

APPENDIX B
PG&E Rule 21 Metering Requirements (Non-NEM Projects)

Voltage Service	Generator Size	PCC Metering	PCC Metering Costs	Net Generation Metering	Net Generation Metering Costs	Phone Line Requirements
Transmission						
60kV & above Transmission	1 MW or greater	Bi-directional meter w/load profile modem & analog outputs	Bi-directional JEMSTAR meter cost - $1,900	Interval Meter w/modem	GE-kV type interval modem meter, cost - $400	Analog phone line
60 kV & above Transmission	100 kW to 999 kW	Bi-directional meter w/load profile and modem	Bi-directional JEMSTAR meter cost - $1,500	Interval Meter w/modem	GE-kV interval meter, w/modem cost - $400	Analog phone line
Primary						
50 kV & below Distribution	1 MW or greater	Bi-directional meter w/load profile modem & analog outputs	Bi-directional JEMSTAR meter cost - $1,900	Interval meter w/modem or mechanical meter w/detent to prevent reverse registration	GE-kV type interval modem meter, cost - $400 Elster mechanical ABS meter, cost - $170	Analog phone line
50 kV & below Distribution	200 kW to 999 kW	Bi-directional meter w/load profile and modem	Bi-directional JEMSTAR meter cost - $1,500	Interval meter w/modem	GE-kV interval meter, w/modem cost - $400	Analog phone line
Secondary						
Single-Phase New Installation	20 kW or less	Low-side metering	Residential meter type GE I-70S w/detent, cost - $30	Class 200 meter w/detent	Class 200 meter mechanical type GE I-70S w/detent, cost -$30	Not applicable
Three-Phase New Installation	21 kW t 199 kW	Low-side metering	Class 20 meter Elster type ABS w/detent cost - $155	Class 20 w/detent equivalent electronic	Class 20 mechanical Elster ABS series meter, cost - $155 Solid-state GE-kV meter, cost - $130	Not applicable

Notes:
1. Net generation metering will require instrument transformers depending on generator's output voltage and size of meter panel.
2. Customer is required to furnish necessary meter panel or switchboard with the instrument transformers usually furnished by PG&E.
3. Net generation and revenue metering installations should be a 4-wire system. Please contact Field Metering group during the early design process to prevent energization delays.
4. Customers with a demand of 200 kW or higher will require installation of an interval type meter with remote communication capability. The customer shall install, own, and maintain a separate, nominal 1 inch conduit and telephone cable extending from the meter panel location to the closest telephone service location. (Contact PG&E for specific requirements).
5. This matrix is intended as a quick information guide. This matrix does not supercede relevant tariffs, legislation, and CPUC decisions.
6. Costs are estimates of meters only. Other applicable costs for labor, ITCC and cost-of ownership charges would apply in accordance with Electric Rule 2.
7. Other metering configurations are possible, as approved by PG&E. For projects larger than 1 MW, the CAISO may impose additional metering requirements.
8. PG&E will install, own, and maintain all PCC and net generation metering unless directed otherwise by the CPUC. The PCC is the Point-of-Common-Coupling.

APPENDIX C
Comparison of Rule 21 and Massachusetts Dispute Resolution Process

Issue	Rule 21 Approach	Massachusetts Approach
Applicability	Current: Only utility; Proposed: Both utility and generator/customer	Both utility and generator
Overall Steps of Resolution	2 steps: (i) good faith negotiation; (ii) adjudicatory proceeding before the CPUC	Steps: (i) good faith negotiation; (ii) meeting before the Department; (iii) mediation; (iv) non-binding arbitration; (v) adjudicatory proceeding before the Dept.
First Step of Dispute Resolution		
-- What is it?	Good faith negotiation	Good faith negotiation
-- How is it initiated?	In writing by the generator (current) or either of the parties (proposed)	In writing by one of the parties
-- Who participates?	"Authorized representatives"	"Vice President or senior management"
-- How long does it last?	45 days	8 days
-- What happens if the step fails?	One or both of the parties may initiate step 2	One or both of the parties may initiate step 2
Second Step of Dispute Resolution		
-- What is it?	Complaint before the CPUC[24]	Meeting before a Dept. Hearing Officer or staff person to work out dispute
-- How is it initiated?	Current rules allow generators and customers (but not utilities) to make a written filing, in conformance with CPUC Rule 10	One party submits a written request with a summary of the dispute
-- Who participates?	CPUC ALJ, plus counsel from the parties	Dept. Hearing Officer or Staff Person, plus unspecified representatives from the parties
-- How long does it last?	Unspecified, except that an "expedited" process is available for small claims type issues in which a hearing will be held within 30 days	The meeting will take place within 14 days of the request
What happens if the step fails?	If one of the parties is dissatisfied with the Department decision and sufficient legal grounds for an appeal, the party may appeal the decision to state court	Step 3 is initiated
Third Step of Dispute Resolution		
-- What is it?	N/A	Mediation
-- How is it initiated?	N/A	Follows from step 2
-- Who participates?	N/A	A mutually-agreeable mediator; a mutually-agreeable technical expert (if needed); unspecified representatives from the parties
-- How long does it last?	N/A	Selection of mediator and technical representative will take 7 days; once commenced, it should be completed within 30 days
What happens if the	N/A	Step four is initiated

[24] CPUC Rules foster informal resolution. Rule 10 states, "A complaint which does not allege that the matter has first been brought to the staff for informal resolution may be referred to the staff to attempt to resolve the matter informally."

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Issue	Rule 21 Approach	Massachusetts Approach
step fails?		
Fourth Step of Dispute Resolution		
-- What is it?	N/A	Non-binding arbitration (i.e., the mediator from step 3 issues a recommended resolution of the matter)
-- How is it initiated?	N/A	Follows from step 3
-- Who participates?	N/A	Same as under step 3
-- How long does it last?	N/A	Unspecified
What happens if the step fails?	N/A	If one of the parties does not accept the recommendation, then one or both of the parties may initiate step 5
Fifth Step of Dispute Resolution		
-- What is it?	N/A	Dept. adjudicatory proceeding
-- How is it initiated?	N/A	One of the parties must make a written request
-- Who participates?	N/A	(Similar to CPUC process)
-- How long does it last?	N/A	Hearings and Briefs are to be completed within 90 days; the Dept. is to decide the matter after an additional 20 days unless it extends this deadline
What happens if the step fails?	N/A	If one of the parties is dissatisfied with the Dept. decision and sufficient legal grounds for an appeal, the party may appeal the decision to state court